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A review of biomass co-firing in North America

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ABSTRACT

Biomass fuels have long been accepted as useful renewable energy sources, especially in mitigating greenhouse gases (GHG), nitrogen oxides, and sulfur oxide emissions. Biomass fuel is carbon neutral and is usually low in both nitrogen and sulfur. For the past decade, various forms of biomass fuels have been co-combusted in existing coal-fired boilers and gas-fired power plants. Biomass is used as a supplemental fuel to substitute for up to 10% of the base fuel in most full commercial operations. There are several successful co-firing projects in many parts of the world, particularly in Europe and North America. However, despite remarkable commercial success in Europe, most of the biomass co-firing in North America is limited to demonstration levels. This review takes a detailed look at several aspects of biomass co-firing with a direct focus on North America. It also explores the benefits, such as the reduction of GHG emissions and its implications. This paper shows the results of our studies of the biomass resources available in North America that can be used in coal-fired boilers, their availability and transportation to the power plant, available co-firing levels and technologies, and various technological and environmental issues associated with biomass co-firing. Finally, the paper proffers solutions to help utility companies explore biomass co-firing as a transitional option towards a completely carbon-free power sector in North America.

Contents

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1. Introduction

Biomass is a renewable energy source that has the potential benefits of decreasing pollutant generation and being CO_2 neutral. One of the oldest sources of energy known to man, it is derived from organic matter such as agricultural crops, forest harvest residues, seaweed, herbaceous materials, and organic wastes [1–4]. Compared to other sources of energy, biomass offers some unique advantage with respect to the environment since it is "carbon neutral". Although the combustion of biomass generates as much carbon dioxide as do fossil fuels, the carbon dioxide released is removed when a new plant grows. This means the biomass expels the carbon (usually in the form of carbon dioxide) that it had originally taken in from the atmosphere, thereby reducing net carbon emissions significantly [5,6].

Biomass co-firing is regarded as one of the attractive short-term options for biomass in the power generation industry. It is defined as the simultaneous blending and combustion of biomass with other fuels such as coal and/or natural gas in a boiler in order to generate electricity [7–10]. Solid biomass co-firing is the combustion of solid biomass fuels like wood chips and pellets in coal-fired power plants [10]. Gas biomass co-firing is the simultaneous firing of gasified biomass with natural gas or pulverized coal in gas power plants in a technique usually referred to as indirect co-firing [11,12]. In both situations, whenever there is insufficient biomass feedstock, the primary fuel buffers the system until the biomass supply improves.

Co-firing biomass with fossil fuels like coal and natural gas offers several opportunities, especially to utility companies and customers, to protect the environment by minimizing GHGs [5]. It also creates opportunities in industries such as forestry, agriculture, construction, manufacturing, food processing, and transportation to better manage large quantities of combustible agricultural and wood wastes [1]. In addition, the cost of adapting an existing coal power plant to co-fire biomass is significantly lower than the cost of building new systems dedicated only to biomass power [13,14]. Even a dedicated biomass plant offers significant environmental benefits. However, relying solely on biomass is risky due to unpredictable feedstock supply because of the seasonal nature of biomass resources as well as poorly established supply infrastructure in many parts of the world [1,5]. Other constraints of generating power solely from biomass are the low heating values and the fuel's low bulk densities, which create the need transport large units of biomass [7]. Biomass co-firing for power generation provides an effective way to overcome these challenges.

This paper reviews biomass co-firing with a focus on North America. The specific objectives include: (1) a review of different biomass co-firing technologies, (2) a review of biomass co-firing in North America, (3) a review of possible approaches to improve biomass co-firing, (4) a comparative assessment of co-firing in North America and around the world and (5) a discussion on opportunities and the future of co-firing in North America due to policies.

2. Existing co-firing technologies

Biomass feedstock can be mixed with coal outside the boiler, or it can be added to the boiler separately. Co-firing technologies are usually implemented in existing coal-fired power plants. The most common type of co-firing facility is a large, coal-fired power plant, though related coal-burning facilities, like cement kilns, coal-fired heating plants, and industrial boilers can be used [9,15].

Al-Mansour and Zuwala [16] list three technological approaches of co-firing biomass with coal or natural gas in a power plant. The approaches differ in terms of the boiler system design as well as the percentage of biomass to be co-fired, and these are: direct co-firing, indirect co-firing, and parallel co-firing.

2.1. Direct co-firing

Direct co-firing is a simple approach and the most common and least expensive method of co-firing biomass with coal in a boiler, usually a pulverized coal (PC) boiler. As shown in Fig. 1, in direct co-firing technology biomass is fed directly into the furnace after either being milled together with the base fuel (Fig. 1a) or being milled separately (Fig. 1b) [17]. The fuel mixture is then burned in the burner. The co-firing rate is usually in the range of 3–5%. This rate may rise to 20% when cyclone boilers are used, although the best results are achieved with PC boilers [18,19].

Maciejewska et al. [15] notes that most direct co-firing issues are a result of high co-firing levels, poor biomass quality, and lack of dedicated infrastructure. Studies carried out by the Tennessee Valley Authority (TVA) show that blending biomass fuels like wood waste (for example sawdust) directly with coal in a PC boiler tend to have an unfavorable impact on the pulverizer and lead to unacceptable sieve analyses results as the co-firing percentages of the system starts to exceed 5% on a mass basis [20]. Depending on the type of biomass feedstock used, some challenges may be encountered when biomass is directly blended on the coal pile. For example, straws and switchgrass can plug the bunkers if they are milled to 25–50 mm (1–2 in.) in length. Also, bark may affect milling operations since it can be very stringy. When pulverizers are not used, cyclone boilers are recommended, although the coal should be crushed to a particle size of 6 mm $\times$ 0 mm (1/4 in. $\times$ 0 in.). However, there is a capacity limit that hinders the quantity of biomass that may be fired when cyclone boilers are used. This is based on the higher heating value of biomass feedstocks, which exceeds the design limits of most cyclone boilers (they would usually have a heating value of about 20 MJ/kg). Also, even though some experts specify an ash concentration level of approximately 5%, the ash concentration of different types of biomass fuels varies significantly from 0.44 in. white pine to 7.63 in. switchgrass, as shown in Table 2. The inherently high ash concentration levels of some biomass fuels like those from herbaceous materials might be a challenge in the boilers since there is a higher tendency of ash deposition problems like slagging and fouling as well as the corrosion of the boiler heat transfer surfaces [7,20,21].

2.2. Indirect co-firing

Indirect co-firing technology allows biomass to be co-fired in an oil- or gas-fired system. It exists in two forms, gasification-based co-firing and pyrolyzation-based co-firing. In gasification-based

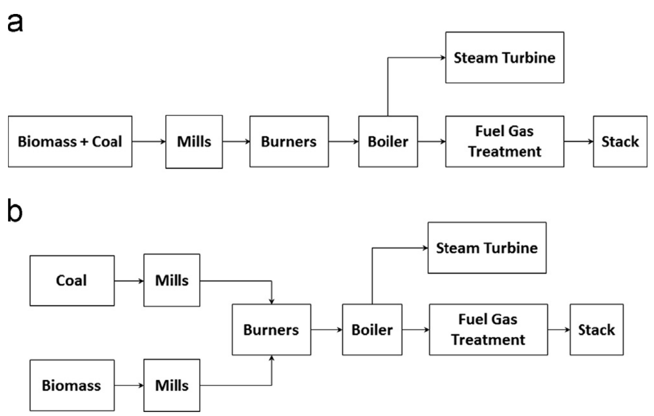

Fig. 1. Direct biomass co-firing technologies: (a) Mixing biomass with coal. (b) Separate biomass feeding arrangement.

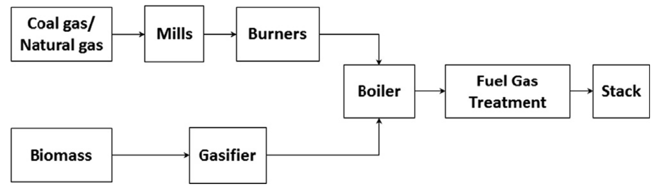

Fig. 2. Indirect biomass co-firing technologies.

co-firing, the biomass feedstock is fed into a gasifier at the early stages of the process to produce syngas which is rich in CO, CO_2 H_2, H_2O, N_2, CH_4, and some light hydrocarbons. This syngas is then fired together with either natural gas or gasified coal in a dedicated gas burner. The net heating value of the syngas produced from the gasification process has an inverse relationship with the moisture content of the feedstock [20,22,23], which, for the biomass fuels in this paper, ranges from 8% in corn stover to 38% in white pine (as shown in Table 2). The negative impact of moisture content is mainly because: 1. Higher moisture content consumes more energy for drying, which reduces the energy converted into syngas and 2. Higher moisture content in the feedstock leads to higher vapor content in the syngas, which reduces the percentage of the combustible gases (CO, H_2) in the syngas.

The other kind of indirect co-firing is based on pyrolysis, where the biomass fuel undergoes a destructive distillation process to produce a liquid fuel like bio-oil as well as solid char, and then the bio-oil is co-fired with a base fuel such as natural gas in a power station [24]. It is worth mentioning at this stage that this technology is yet to record any commercial success given that it is still under a development and demonstration phase. An illustration of indirect biomass co-firing is shown in Fig. 2.

Gasification-based co-firing in PC boilers has been successfully demonstrated in Lahti, Finland with a wide range of biomass fuels such as sawdust, straws, wood wastes, and other waste-derived fuels [25]. Its commercial acceptance has increased significantly through the aid of the recent successful commercial operation of a fluidized bed gasifier. Evidence shows that the most suitable gasification technology for indirect co-firing is fluidized bed gasification, whether in the form of bubbling fluidized bed gasification or circulating fluidized bed gasification, since they permit the use of a wide range of biomass fuels. Gasification-based co-firing technology in the demonstration plant in Finland addresses several co-firing issues when compared with conventional co-firing technologies, such as: 1. This technology prevents biomass material from being fed into the boiler in a solid form, which in turn reduces boiler slagging and prevents the alteration of the ash characteristics, 2. Gasification is able to accomplish complete combustion in the furnace with a very short gas residence time [26], 3. Gasification-based co-firing can potentially substitute higher percentages of biomass gas in the system, although its effect on combustion efficiency, boiler efficiency, and emissions from pollutants is yet to be determined [26], 4. Gasification offers a unique advantage in that it is fuel-flexible in terms of the base fuel used since it can accommodate coal, oil, and natural gas [20]. However, the major concerns associated with this technology, especially in the large-scale application, are in achieving and maintaining very high level product gas purity and its high capital costs. These issues make indirect co-firing the least successful commercial co-firing technology [25].

2.3. Parallel co-firing

In parallel biomass co-firing technology, as shown in Fig. 3, biomass pre-processing, feeding, and combustion activities are carried out in separate, dedicated biomass burners. Parallel co-firing involves the installation of a completely separate external biomass-fired boiler in order to produce steam used to generate electricity in the power plant [27]. Instead of using high pressure steam from the main boiler, the low pressure steam generated in the biomass boiler is used to meet the process demands of the coal-fired power plant [27].

Parallel co-firing offers more opportunity for higher percentages of biomass fuels to be used in the boiler [27]. This technology also offers lower operational risk and greater reliability due to the availability of separate and dedicated biomass burners running in parallel to the existing boiler unit. There is a reduced tendency for deposition formation issues like fouling and slagging, as well as corrosion, since the system design prevents biomass flue gas from contacting the boiler heating surfaces and the combustion process is better optimized. However, this technology is more capital intensive than direct co-firing due to the dedicated boiler system [28]. Its application is commonplace in industrial pulp and paper facilities where it makes use of by-products from paper production like bark and waste wood.

3. Levels of co-firing

Generally, there is a large possibility that biomass co-firing can reduce CO_2 emissions given that a significant amount of biomass can be co-fired with a base fuel like coal or natural gas in a boiler. The amount of biomass fuel that is co-fired is called the co-firing level or the rate of co-firing. Although it is believed that biomass can potentially be substituted for more than 50% of the coal used in a co-firing configuration, at present the actual co-firing level achieved in most commercial applications is up to 5–10% [10]. This significant shortfall is largely caused by the current inability to effectively manipulate several logistical, technical, and economic factors such as the origin and quality of the biomass used as well as its supply chain, plant set-up in terms of boiler type and efficiency, environmental issues including emissions from sulfur and nitrogen oxides, the overall quality of the by-products' (e.g., fly ash, bottom ash, and gypsum) deposition and corrosion formation, and the deterioration of downstream gas cleaning systems [10]. Table 3 shows the range of co-firing levels for different boiler types as well as a technical comparison of the boilers.

Higher biomass co-firing levels are generally achieved with fluidized bed boilers and cyclone boilers rather than with pulverized coal-fired or grate-fired boilers, though pulverized boilers are more commonly used [29,30]. This is because PC boilers and grate-fired boilers are limited by the particle size of the biomass fuel they are only able to grind (pulverize) the biomass fuel to a fine powder of less than 10–20 mm, through they can grind coal

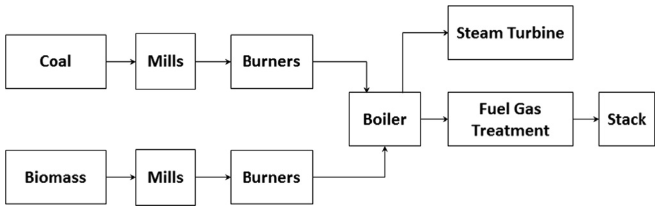

Fig. 3. Parallel biomass co-firing technologies.

particles to 75–300 μm. This disparity leads to serious challenges as the co-firing level increases. While this challenge is eliminated through both the fluidized bed boiler and cyclone boiler, the boilers offer other advantages such as increasing the choice and nature of biomass fuel that can be used as well as the possibility of reducing NO_x and SO_x emissions [9]. Table 3 shows the range of the co-firing levels that can be achieved by these boiler technologies [16,31,32]). Usually, the boiler types used for biomass co-firing record little or no loss in total boiler efficiency after adjusting combustion output for the new fuel mixture. Therefore, the efficiency of biomass feedstock combustion to electricity may range from 33% to 37% when biomass feedstock is co-fired with coal. However, a high percentage of biomass co-firing generally results in a drop in the efficiency and power output of the system. It is estimated that about 150 GW of power (i.e., up to 2.5 times more than the current globally installed biomass power capacity) can be generated if the current installed coal-fired electricity capacity is co-fired with biomass at a rate of 10% [7,10].

The net electric efficiency of a typical biomass co-firing plant usually ranges from 35–44%. Evidence shows that direct co-firing is usually slightly more efficient (roughly 2% more) than the other co-firing technologies due to the conversion losses that occur in the biomass gasifiers and boilers [10]. However, the efficiency of direct co-firing plants decreases when biomass co-firing rates or levels increase due to fouling and slagging and associated corrosion that may occur in the boiler. This is more commonplace in grate-fired (stoker) boilers. Moreover, modern, large, and highly efficient power plants achieve significantly higher biomass conversion efficiency compared to small (less than 10–50 MW) dedicated biomass power plants. The economy of scale of such large power plants contributes to lower energy costs per unit of biomass fuel used [1,10,33].

4. Technical and logistical issues

To reduce GHG emissions significantly, more biomass should be consumed. However, with greater biomass consumption, there are technical issues related to its unstable supply [2]. Large amounts of quality biomass can be achieved when co-firing plants are located close to abundant sources of desirable biomass fuel types; when more expensive but reliable, dedicated energy crops are used or there is international biomass trade in cases where the local infrastructure will not support sufficient biomass supply; and when biomass pre-treatment technologies like pelletization, briquetting, and torrefaction are applied to enhance biomass handling and transportation [34].

Biomass co-firing may be affected by the following technical and logistical issues:

1. Fuel, including fuel type, availability, and quality; fuel logistics, required fuel handling and transportation, pre-processing (drying, milling), and storage capacity; the price of the biomass feedstock, compared to the relatively low cost of coal; the size of the biomass particles for suspension burning in pulverized coal boilers, and the possibilities for injecting biomass into the boiler.
2. Boiler, including boiler/combustor capacity and performance, net power output, burner configuration, flame location and different combustion behaviors, and existing boiler limitations; deposition formation (slagging and fouling effects), corrosion and/or erosion and consequently changes in the life-time of equipment, agglomeration, and sintering.
3. Flue gas cleaning operation and performance.
4. Reduction in ash landfill costs and/or income from ash applications. [1,8,13,28,35].

The rest of Section 4 will provide a detailed analysis of each of these technical and logistical issues.

4.1. Fuel

4.1.1. Fuel type

Biomass is a combustible material usually burned to produce heat that can be used to generate motion in vehicles and electricity in power plants [5]. According to Parry et al. [36], biomass is an organic material or a by-product of an organic material. When co-firing biomass with another fuel type, it is necessary to gain sufficient understanding of the properties of the fuels. The sub-properties of each group of fuel types must be considered as well. Evidence shows that biomass varies drastically from one type and category to another and that properties of coal differ significantly across ranks as well [7].

Generally, biomass can be classified based on its origin as well as its properties. Based on its origin, biomass can be classified into: (a) Primary residues: These include biomass such as wood, straw, cereals, maize, etc., obtained from the by-products of forest products and food crops. (b) Secondary residues: These include biomass such as saw and paper mills, food and beverage industries, apricot seed, etc., derived from processing biomass material for industrial and food production. (c) Tertiary residues: These include waste and demolition wood, etc., that are derived from other used biomass materials. (d) Energy crops [3]. In addition, biomass fuels can also be classified into the following based on their properties: woody biomass; herbaceous biomass; wastes and derivates; and aquatic biomass (kelp, etc.) [37–39]. The major solid biomass materials when considering both origin classification and properties classification are shown in Fig. 4.

Woody biomass is considered to be the most convenient option for co-firing activities. Woody biomass is regarded as a premium biomass fuel because it is naturally low in ash, sulfur, and nitrogen, all of which are highly reactive and volatile entities. Therefore, woody biomass fuels such as forest residues and mill residues like sawdust are the most favorable biomass feedstocks [8]. Both forest and mill residues have been successfully co-fired with coal in many installations in both North America and Europe [19]. Other biomass feedstocks that have been co-fired are agricultural products like straw, switchgrass, corn stover, rice hulls, and olive pits [28]. This review paper focusses majorly on woody and herbaceous fuels since they meet the central goal of co-firing technologies discussed in this paper in terms of fuel properties, co-firing technology, and geographical location.

4.1.2. Fuel properties

The properties of biomass feedstocks vary widely due to their diverse nature, and biomass fuels differ significantly from both coal and natural gas in terms of physical and chemical properties as well as composition and energy content [41]. For example, coal and natural gas (and other fossil fuels) are not considered biomass

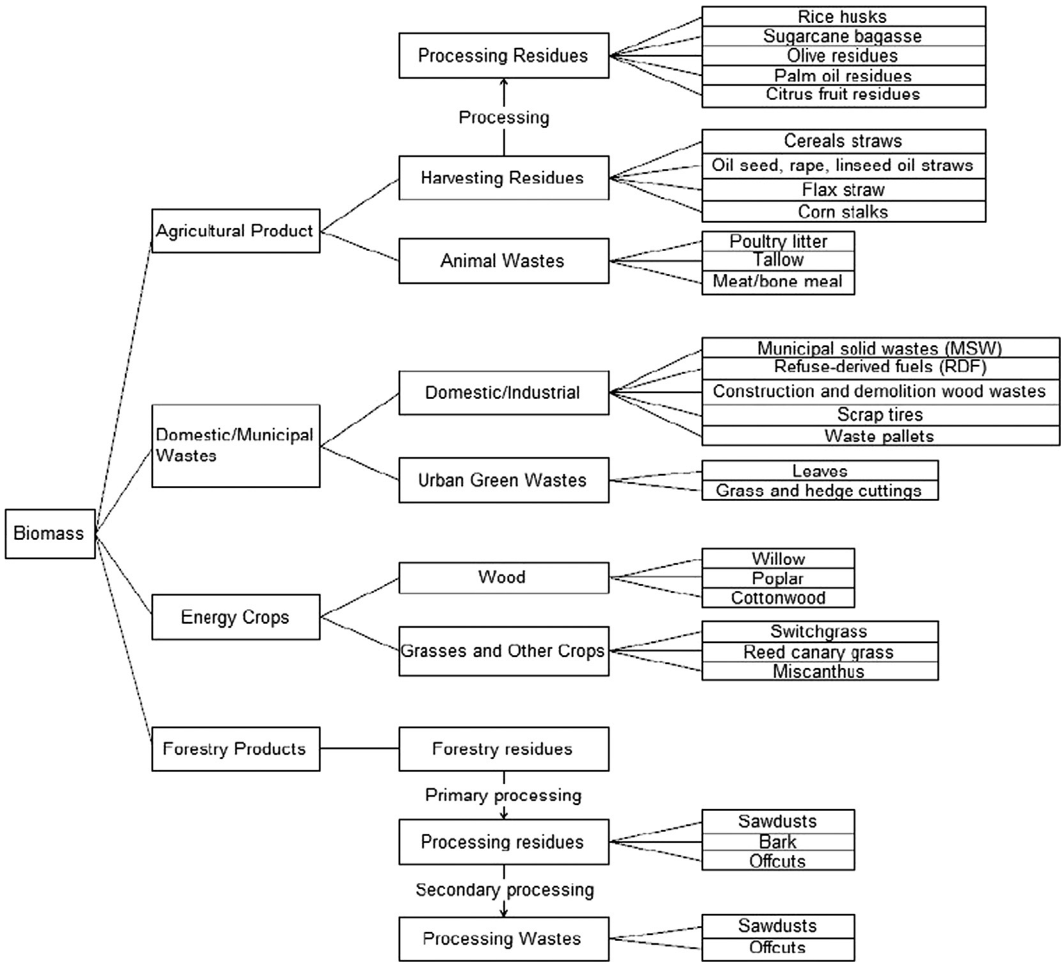

Fig. 4. Major solid biomass materials of industrial interest on a global scale (adapted from [40]).

Table 1
Typical elemental compositions (%) of different forms of biomass and coal fuels [8].

Fuel	C	H	O	N	S	Si	K	Ca	Cl
Anthracite coal	91–94	2–4	2–5	0.6–1.2	0.6–1.2	2–6	0.1–0.5	0.03–0.2	0.01–0.2
Bituminous coal	83–89	4–6	3–8	1.4–1.6	1.4–1.7	2–3	0.1–0.2	0.1–0.3	0.01–0.13
Wood (clean and dry)	50	6.1	43	0.2	–	0.05	0.1	0.04	–
Switchgrass	48	5.5	43	0.2	–	1.4	0.4	0.2	–

Note: C=Carbon; H=Hydrogen; O=Oxygen; N=Nitrogen; S=Sulfur; Si=Silicon; K=Potassium; Ca=Calcium; Cl=Chlorine.

although they trace also their origins to the remains of dead plant and animal materials. The reason for this is that the “carbon” on which fossil fuels are based has not been in the “established carbon cycle” for millions of years. Therefore, the carbon they eventually release during their combustion disrupts the carbon cycle. Some typical elemental compositions of different forms of biomass and coal are shown in Table 1, and a comparison of the typical composition of several biomass fuels and coal based on proximate and ultimate analyses is shown in Table 2. When compared to these fossil fuels, most biomass fuels contain [42,43] less carbon; more hydrogen and oxygen; less sulfur and nitrogen; more volatile material; less heating value; and lower bulk density.

Biomass fuels tend to behave similarly to peat, a low-rank coal, as well as lignite. Biomass fuels have much less carbon and a higher fraction of hydrogen and oxygen compared to peat and lignite, leaving biomass with much less energy density than they have. A typical biomass has only about one tenth of the overall fuel density of coal [5]. Therefore, a 10% biomass co-firing level will be very favorable in terms of magnitude since the volume of the coal involved will be comparable to the flow rate of the biomass [9]. However, co-firing relationship shows that logistics and technologies associated with shipping, storage, and handling biomass will be complex compared to firing only these fossil fuels in a boiler due to its low heat contribution. More deposit formation occurs with biomass combustion than with either coal or natural gas combustion. Such deposits may be hard to remove, even requiring additional cleaning efforts. The emissions of particulate matter that occur during biomass combustion are much higher than those of natural gas or gasified coal [9,34].

Both coal and biomass have similar ignition processes, although biomass fuels may experience more homogenous and flaming combustion due to higher volatile materials (VM). The presence of higher VM in the biomass fuels may affect the optimum sizing and design of

Table 2
Properties of typical biomass fuels compared with coal (adapted from [7,20,44]).

	Typical biomass					Coal	
	Sawdust	Urban wood waste	Switchgrass	Corn stover	White pine	lignite	peat
Proximate analysis (wt%)							
Fixed carbon	9.34	12.5	12.18	15.36	15.1	23.9	29.4
Volatile matter	55.03	52.56	65.19	69.74	84.5	54.0	68.6
Ash	0.69	4.08	7.63	6.90	0.44	22.0	2.0
Moisture	34.93	30.78	15.00	8.00	38	30	35.8
Ultimate analysis (wt%)							
Carbon	32.06	33.22	39.68	42.00	52.5	58.8	56.1
Hydrogen	3.86	3.84	4.95	5.06	6.32	4.17	5.67
Oxygen	28.19	27.04	31.93	36.52	40.6	13.6	35.2
Nitrogen	0.26	1.00	0.65	0.83	0.10	0.91	0.81
Sulfur	0.01	0.07	0.16	0.09	<0.05	0.50	0.23
Ash	0.69	3.99	7.63	6.90	0.44	22.0	2.0
Moisture	34.93	30.84	15.00	8.00	38	30	35.8
HHV—as received (Btu/lb)	5431	5788	6601	7000	8856	9372	9200
Volatile/fixed carbon ratio	5.89	4.20	5.35	4.54	5.60	2.26	2.33

the combustion chamber and other properties like the ideal flow rate and location of combustion air. Experience shows that coal combustion equipment can handle solid biomass feedstock quite easily; the same applies to natural gas equipment and gaseous biomass, although these fuels have different chemical compositions [8,9,34].

While agricultural and herbaceous products (e.g., corn stover and switchgrass) have high ash and volatile contents, the same is not true for woody biomass (e.g., sawdust and urban wood waste) (see Table 2). Also, the heating values of woody biomass and switchgrass are substantially higher than those of agricultural residues such as rice hulls, cotton gin trash, vineyard prunings, etc. On the other hand, the moisture concentration of woody biomass depends jointly on the living and growing processes and on the manufacturing process imposed on the wood. The moisture content in sawdust is usually a result of the machinery used during processing. Compared to most other biomass, the moisture content in herbaceous fuels such as switchgrass is generally lower. However, straw has a significantly high level of volatile matter such as chlorine, and alkaline, but ecological factors such as soil types and weather conditions influence the ash and nitrogen content of the fuel [7].

The heating value of biomass is compromised by its higher proportion of oxygen and hydrogen to carbon atoms. This is because breaking the C–H and C–O bonds of biomass releases less energy compared to the predominately C═C bonds found in coal. Also, biomass has a much higher reactivity when compared to coal due to its higher oxygen content, and this usually results in a lower activation energy barrier to devolatilization and oxidation [16,45].

Several other issues associated with combusting biomass in a coal-fired boiler, such as the low bulk density, high moisture content, ash deposition and fouling problems on hot surfaces, hydrophilic nature, etc., can be mitigated by blending higher ratios of torrefied biomass with fossil coal than with raw biomass. However, torrefied biomass has coal-like characteristics that may lead to drops in energy efficiency and fluctuations in boiler load [46,47].

4.1.3. Fuel cost

The price of biomass is strongly dependent on the following: (a) the feedstock's origin, type, and composition, (b) the cost of handling, preparing, and transporting the feedstock, and (c) the plant's geographic location [48].

The transportation cost over long distances is influenced strongly by the energy density or the heating value of the biomass feedstock. Biomass pre-treatment technologies such as pelletization, briquetting, and torrefaction can be effectively used to increase the heat value per volume of biomass, thereby reducing the overall transportation costs. However, such technologies have extra costs, and the cost of operating a large-scale biomass co-firing plant could exceed the cost of operating an equivalent coal-fired plant, depending on the cost of coal. However, a favorable CO_2 emission allowance price can take care of this price differential [8,9].

4.1.4. Feedstock size and nature

The size and nature of the biomass feedstock should be taken into consideration when designing a co-firing operation. This is because the amount of biomass that can be milled together with coal prior to co-firing is heavily dependent on the physical nature and grindability of the biomass feedstock. For example, the fibrous nature of some biomass prevents it from being processed in a pulverizer boiler-based direct co-firing system. This challenge may be overcome by milling and delivering the biomass to the boiler through an independent line [1,34].

4.2. Boiler type

Most biomass co-firing projects usually use existing coal- or gas-fired combustion technologies since they do not necessarily require a new, dedicated technology to function. With minimal modifications, a coal-designed power plant can be suitable for blending biomass feedstock with coal. Examples of typical coal combustion technologies that can easily be effectively used for biomass co-firing include a fluidized bed combustion boiler (FBC), a pulverized coal combustion boiler (PCC), a packed-bed combustion boiler, and a cyclone boiler [7,28,49]. A comparison of biomass-coal co-firing in different combustion systems is shown in Table 3.

A pulverized coal combustion boiler (PCC) is a popular technology used in converting energy from coal and some other fossil fuels to heat energy, usually in a controlled amount of air, for subsequent use in a boiler. The fuel is finely ground before it enters the combustor. When a PCC reactor is used for a co-firing system, some studies showed that it can reduce NO_x emissions significantly. However, this technology requires high fuel quality since

Table 3
Typical features of common coal combustion technologies in biomass co-firing systems (adapted from [16,31,32]).

Co-combustion system	Operation requirements	Co-firing percentage (% heat)	Technical features
Pulverized combustion	Fuel type: coal, sawdust, and fine shavings; Particle size: < 10–20 mm; Moisture content: < 20 wt%	1–40%	Can decrease NO_x significantly; Limited by biomass particle size and moisture content.
Fluidized-bed combustion	Fuel type: various fuels, better suited for woody biomass than for herbaceous biomaterial; Particle size: < 80 mm (BFB), < 40 mm (CFB); Temperature: < 900 °C	CFB: 60–95.3% BFB: 80%	The fluidized bed combustion system is the most suitable boiler for biomass co-firing. The soot formation is problematic, especially in CFB.
Packed-bed combustion	Fuel Type: wide range of fuels, including coal, peat, straw and woody residues; Particle size: fairly large pieces < 30 mm	3–70%	Not suitable for direct co-firing, although can be used for parallel or in-direct co-firing.
Cyclone combustion	Ash content: > 6%; volatiles: > 15%; except in a dried form, moisture content: > 20%.	10–15% by heat input or 20–30% by mass	Suitable for co-firing since minimal modifications are needed for feeding and mixing the biomass and the coal

the maximum fuel particle size should be 10–20 mm, and the moisture content should be no more than 20 wt%. This lowers the application of this combustion system in co-firing projects [9,31].

Pulverized boilers are not affected by deposition formation problems like slagging, fouling, and corrosion from high concentrations of potassium and chlorine in biomass compared to fluidized or grate-fired boilers. The risk of slagging, fouling, erosion, and corrosion occurring in biomass co-firing can be countered by choosing the right co-firing technologies and feedstock. Also, washing and leaching biomass feedstock in acid, water, or ammonia reduces the feedstock's alkali and ash contents, thereby reducing the possibility of deposition formation and corrosion. This is more important in herbaceous biomass since it is richer in alkali compounds. Washing and leaching biomass, which reduce the amount of alkali compounds in the biomass fuel, can reduce plant maintenance costs [10].

The fluidized bed combustion (FBC) is designed to operate at very high temperatures ranging from 800°C to 900 °C, which lowers the NO_x and SO_x emissions compared to other combustion technologies [14]. A fluidized bed combustor is the most suitable reactor for co-firing. The fuel types that can be used in the FBC boiler system are low-grade fuels like peat, woody biomass like forest residues, wood wastes, industrial wastes like sawdust, and municipal solid wastes (MSW) [51]. A fluidized bed boiler operating on direct co-firing technology is less sensitive to any changes in the overall efficiency as the biomass level increases, although this may require a more sophisticated boiler and fuel handling control system. Fluidized bed boilers are also more capable of handling biomass with higher moisture content (10–50% instead of < 25%) and larger particle sizes (< 72 mm instead of < 6 mm) than pulverized boilers [10].

The fuel-particle mix is suspended by an upward flow of combustion air within the bed, which acquires more fluid-like properties as velocities increase. While the bubble fluidized bed combustion boilers (BFBC) usually operate at a lower air velocity when compared to the transport velocity of the fuel particles, the circulating fluidized combustion boilers (CFBC) are designed to have a significantly high gas velocity that entrains the fuel and bed particles in the gas flow exiting the combustion chamber, from where these particles will be separated in a beam separator or cyclone and then recirculated back to the system [49,51].

The packed-bed combustion system uses a stoker or grate combustion boiler and is designed to allow the fuel to be fed onto a moving grate as a controlled amount of air is steadily blown onto the fuel. During its operation, the fuel particles are steadily moved to the front of the boiler from the back as the larger particles are burned directly on the grate, while the smaller fuel particles burn in the air adjourning the grate. The system can fire different types fuels, such as peat, coal, or biomass feedstocks like straw and woody residues in several sizes (up to 3 cm), which makes it suitable for biomass co-firing. Some researchers have paid attention to the direct co-firing in a packed-bed combustion system [52]. However, that system has a few technical flaws such as lower thermal efficiencies, the tendency of ash to sinter on the furnace, the need to feed the fuel into the combustor in a high rank, coarse particle form, and the cost of cleaning out ash particles from the flue gas, all which make it less desirable for co-firing biomass with coal [3,28,52]. Moreover, one big technical difficulty of the packed-bed combustion system is that it is not suitable for direct co-firing, although it can be applied in parallel or in-direct co-firing technologies. Finally, although the packed-bed combustion boiler produces high electrical power, and its operational and maintenance costs are low, its low thermal efficiency when compared with the FBC and PCC limits the extensive application of this system.

The cyclone boiler system is designed with large, water-cooled burners that are placed in a horizontal position, and its external furnace can reach combustion temperatures in the range of 1650 °C and 2000 °C. The boiler allows the fuel's mineral matter to form a slag capturing the over-sized particles and to combust the fine and volatile fuel particles in suspension. The intense heat that radiates from this design burns up the layer of slag formed [49]. The fuels that can be burned in a cyclone boiler include a variety of coal and biomass feedstocks, and they are best when crushed. This technology is suitable for biomass co-firing, though a few modifications may be necessary to enhance the feeding and mixing of the biomass and the coal. For optimum performance, certain requirements are specified for the fuels that can be fired on a cyclone boiler. Based on these specifications, the ash content must exceed 6%, volatiles are expected to be greater than 15% of the fuel, and, except in a dried form, the moisture content of the fuel must not be less than 20%. These requirements may be a bit challenging for some pure biomass types [28,32].

Except with direct co-firing in existing combustion systems as discussed before, the gasification technology is meant to be used in an indirect co-firing system. Fixed bed gasifiers are generally used in small-scale applications involving fuels with specific physical characteristics. Generally, their applications are limited to less than 10–15 MWe power capacity. The fluidized bed gasification has been identified as the most effective gasification technology for indirect biomass co-firing. The technology uses a wide variety biomass fuels as well as waste-derived fuels that differ in terms of their heating value, density, and other characteristics. Both the bubbling fluidized bed (BFB) gasification and circulating fluidized bed (CFB)

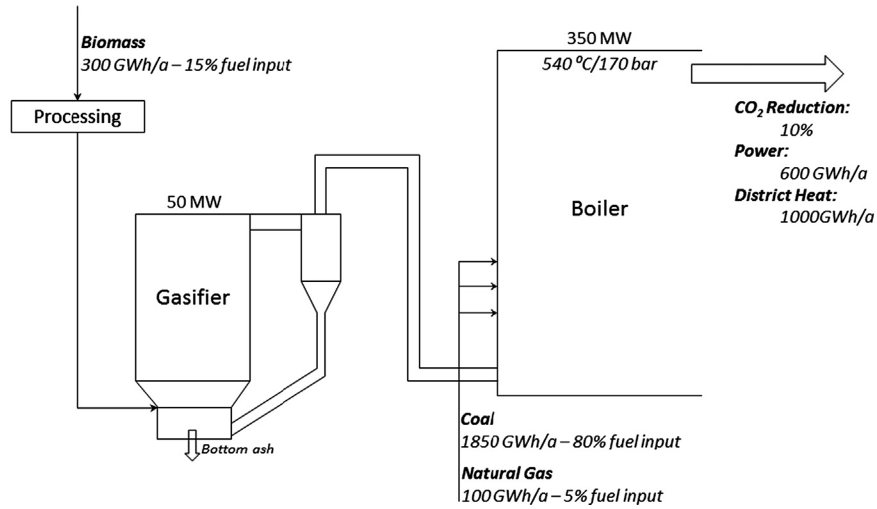

Fig. 5. Biomass gasification systems used for indirect co-firing in Kymijärvi power plant, Finland (adapted from [24]).

gasification can be applied. One major example of commercial biomass gasification systems is in the Kymijärvi power plant in Lahti, Finland. The arrangement is illustrated in Fig. 5. The system is based on a CFB gasifier and uses coal and natural gas, as well as biomass and waste-derived fuel. The burners are equipped with flue gas circulation and staged combustion to control NO_x emissions. However, since the sulfur content of the coal is relatively small (0.3–0.4%), the system does not have a sulfur removal system [10,24].

Other major issues in biomass co-firing are the corrosion of boiler surfaces and deposition formations due to the reaction of chlorine with alkali metals such as potassium and sodium. This is commonplace when herbaceous biomass is used since it is rich in chlorine and alkali. Tillman et al. [41] write that woody biomass is less likely to contribute to corrosion and deposition since it is lower in alkaline and chlorine.

5. Regulatory and environmental considerations

Since the properties of biomass fuels vary significantly with those of both coal and natural gas, blending biomass with any of these fuels offers many environmental and economic benefits [1]. According to Tillman et al. [7], biomass co-firing was originally put forward as a useful tool for utility companies to meet the following environmental goals: (1) help reduce carbon dioxide emissions from fossil fuels in line with the voluntary global climate challenge program; (2) help reduce other airborne emissions like oxides of sulfur (SO_x) and nitrogen (NO_x), and trace metals.

Biomass co-firing can contribute significantly to the reduction of SO_x and NO_x emissions given that most biomass contains less sulfur and nitrogen than coal [14,41]. However, the net reduction of CO_2 emissions and other pollutants is strongly influenced by the origin and supply chain of the biomass feedstock [10].

5.1. CO_2 emissions

Compared to conventional power generation (i.e., solely coal- or gas-fired plants), biomass co-firing has a huge potential to reduce GHG emissions and to produce power at a relatively low initial cost. Very few net GHG emissions are released from co-fired power plants because the net CO_2 from the combustion of biomass is reduced to almost zero when the effects of photosynthesis are taken into account. Biomass co-firing can further yield negative GHG emissions (i.e., net removal of CO_2 from the atmosphere) if used in combination with carbon capture and storage (CCS) technologies such as biogenic carbon sequestration. This technology is more financially attractive than building dedicated biomass-fired plants since the incremental investment costs for retrofitting or building new co-fired power plants are much lower than building a dedicated biomass-fired plant. However, co-firing biomass is generally more expensive than generating electricity solely through coal or natural gas. Since the current market prices of natural gas and coal are relatively lower than those of biomass, utility companies may be reluctant to favor biomass co-firing over the other power generation options [9].

5.2. NO_x and SO_x emissions

Coal-fired power plants emit flue gases that contain much more SO_x and NO_x than are found in the gases emitted from a co-fired plant. This is because coal contains more sulfur and nitrogen than biomass does. When SO_x and NO_x are released into the atmosphere, depending on their scale, they may create air pollution such as acid rain or deplete the ozone. Biomass co-firing could reduce the level of SO_x and NO_x emissions, thereby contributing significantly in decreasing air pollutants [5,53].

However, the use of biomass fuels may pose some operational challenges, for example, the way the biomass is handled and transported differs from how the main fuel is handled; and dealing with slagging, corrosion, and fouling associated with the ash content from the biomass may lead to higher maintenance and replacement costs.

Compared to the biomass derived from agricultural residues, biomass fuels derived from forest residues have a lower tendency to produce less NO_x, SO_x, and particulate emissions during combustion, because they contain less nitrogen, sulfur, and ash. With respect to coal, lignite offers some environmental advantages, such as relatively low sulfur content, although not comparable to biomass. Some of the SO_x produced during the combustion in the lignite power plant can be absorbed by the higher ash contents of CaO and MgO before it is emitted, forming $CaSO_4$ and $MgSO_4$ [44,54].

Generally, NO_x is formed during combustion in one of three different reactions, thermal NO_x, prompt NO_x, and fuel NO_x. Thermal NO_x is formed from nitrogen in the air at high temperatures, while prompt NO_x is formed in the presence of hydrocarbons. Lastly, fuel NO_x forms as a result of nitrogen-containing fuels. In a biomass co-firing operation, the main sources of NO_x are thermal NO and fuel NO from coal while NO_x originating from biomass fuel has little effect. The thermal NO_x is usually formed on the highest level of

coal burners in the boiler while low NO_x is formed in the lower levels. The level of NO_x emissions reduces steadily as the percentage of wood chips co-fired with coal increases [44,55].

Badour and Gilbert et al. [44] studied the emissions content from co-firing a Canadian lignite coal with a Canadian peat and a woody biomass in a BFBC boiler. The NO_x and SO_2 emissions per energy input obtained when peat pellets or pine pellets are blended and fired together with lignite at 0%, 20%, 50%, 80%, and 100% on a thermal basis are shown in Fig. 6. Co-firing lignite and white pine pellets decreases both NO_x and SO_2 emissions. As with the influence of biomass fuels on NO_x emissions, SO_x emission levels reduce gradually as the amount of biomass fuel co-fired with coal increases [56].

5.3. Ash

One of the issues associated with biomass co-firing is how to deal with the ash left over after the combustion of both of the fuels in the combustor. This is because using the ash produced from combustion may be necessary for environmental reasons as well as for the plant performance [8]. Generally, the co-firing technology employed determines the nature of the ash left at the end of the combustion process. For example, a mixture of biomass and coal ash is obtained from a direct biomass/coal co-firing operation, while separate biomass and coal ashes can be obtained after an indirect or parallel biomass co-firing operation. Also, the ash contents of different biomass and coal feedstocks differ significantly in composition (see Table 2). For example, herbaceous feedstocks have higher ash contents than wood biomass feedstocks since they take in more nutrients during growth, while the bark content of woody biomass feedstocks have higher ash content and levels of mineral impurities such as sand and soil [9].

In many parts of the world, these ashes are sold to some target buyers who use them for different purposes. For example, fly ash obtained from the combustion of biomass is used as raw material in the production of concrete used in the construction industry. The ash can also be used for fertilizer production since it is rich in Mg and Ca, though this use may be hindered by the lack of nitrogen and soluble phosphorous in the ash. Also, fly ash from the gasification of biomass in the fluidized bed can be reused as fuel for power generation since it has a high energy content rich in unburned carbon. Research shows that this is the most favorable choice economically. Furthermore, different forms of coal ash like boiler slag, fly ash, and bottom ash are used in the construction industry and in underground mining, as well as the restoration of open cast mines, pits, and quarries [1].

6. Opportunities for North America

The carbon tax, also known as the carbon abatement cost, is a form of pricing on GHG emissions that requires individual emitters such as energy companies and other consumers to pay a specified fee, charge, or tax for every tonne of GHG that they release into the atmosphere [68].The logic behind this policy is that mandating emitters to pay the carbon tax motivates them to weigh the cost of emissions control against the cost of emitting and paying the tax. Eventually emitters will likely adopt those cheaper emissions-reductions programs rather than pay the tax, while those programs that are more expensive the emitters may not implement. Those who favor this cost-effective approach will help equalize the marginal cost of abatement [69,70].

In order to achieve greater success, especially with respect to the overall emissions limit, it is necessary that the carbon taxes are uniform and sensitive to changes in the system. This means that the emission tax level should be adjusted to: (1) meet the emissions standard that has been jointly approved by most countries in the world; (2) continually correspond to changing external factors like inflation, technological progress, and new emissions sources [33,57].

Generally, carbon taxes place a direct price on the tonne of GHG emitted through man-made activities such as the production and use of energy especially from hydrocarbons. For example, there are up to 150 taxes levied on energy products and 125 taxes on motor vehicles, as well as some direct taxation of CO_2 emissions across some OECD (Organization for Economic Co-operation and

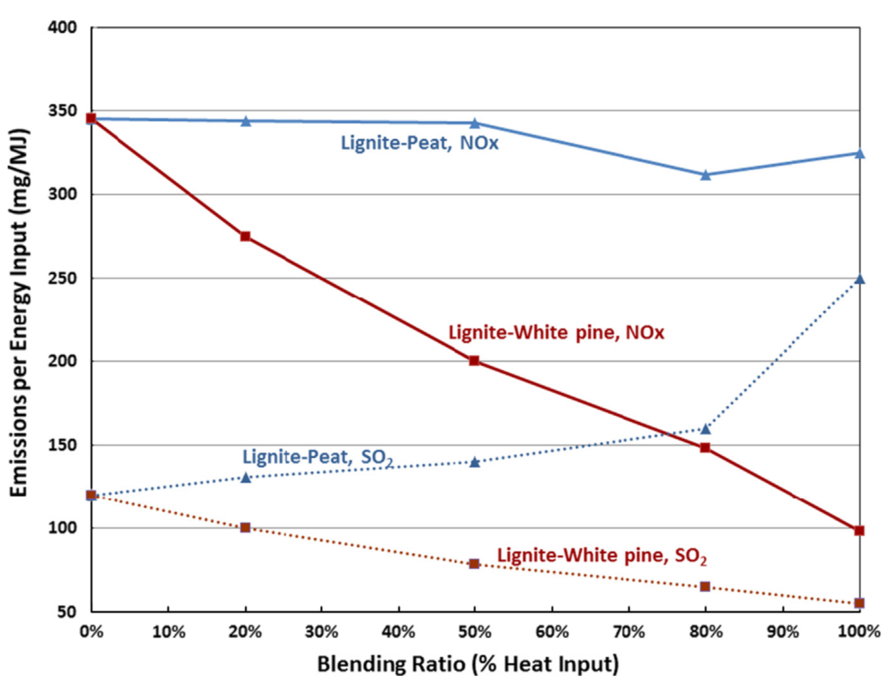

Fig. 6. The effects of lignite-peat co-firing and lignite-white pine co-firing on NO_x and SO_2 emissions (adapted from [44]).

Development) countries such as Australia and New Zealand and the Nordic countries [29]. There is no existing federal emission tax levied in either Canada or the United States of America. However, the tax is found in various forms in several provinces and states. For example, the Government of Alberta presently levies a tax of \$15 per tonne of CO_2 in Alberta. Different forms of carbon taxes are also found in Quebec, Maryland, California, and Colorado [72,73].

As mentioned above, carbon taxes offer a potentially cost-effective tool for reducing overall GHG emissions. A carbon tax gives energy companies a real incentive to reduce a significant portion of their overall GHG emissions. Biomass co-firing can be viewed as a useful emissions reduction tool in the power generation industry since it can enable utility companies that generate electricity through coal power to reduce their over GHG emissions significantly by substituting a portion of their base fuel, if it is coal or natural gas, with a "carbon-free" fuel such as biomass [11].

7. Possibility of increasing the scale of biomass co-firing

Co-firing biomass and fossil fuels is advantageous especially to utility companies and customers not only because of cost savings but also because this technology protects the environment by minimizing GHGs [5]. Co-firing also creates an opportunity in industries such as forestry, agriculture, construction, manufacturing, food processing, and transportation to better manage large quantities of combustible agricultural and wood wastes [1]. However, several technical barriers associated with co-firing biomass and fossil fuels have been identified, such as the availability of quality biomass fuels, limits to the percentage of biomass that can be fired under given configurations, and issues associated with boiler performance, deposition formation, corrosion, etc. [10]. Several solutions have been developed to address these challenges, including pretreating the biomass fuels in order to reduce their high moisture content, thereby improving their transportation and storage, and government policies in some countries that require utility companies to sell fly ash (a product of the combustion process) as an active raw material in the making of Portland cement and concrete. It is believed that the second requirement may encourage more utility companies to adopt co-firing since they will be able to sell the ash [34].

7.1. Technical issues

7.1.1. Pretreatment

Several issues associated with the handling and combusting of biomass in a boiler can be improved significantly through pretreatment methods such as pelletization or torrefaction. Biomass pretreatment reduces the overall cost of handling, storage, and transportation and improves transport and storage characteristics. Since these technologies enhance homogeneity in terms of fuel use, they minimize the investment of plant infrastructure and also reduce the overall operation and maintenance costs [58].

According to IEA-ETSAP and IRENA [10], pelletization is a technique that improves the energy density of fuel. The compact cylindrical shape of a biomass pellet enables it to repel moisture, thereby solving the low bulk density problems of most biomass as well as the corresponding logistics and storage issues associated with it. Both woody and herbaceous biomass can be pelletized, and evidence shows that pellets are the most suitable biomass-derived feedstock for biomass co-firing operations [9,14].

Torrefaction is the thermo-chemical treatment of biomass in the absence of oxygen at very high temperatures of up to 200–300 °C for nearly an hour. The result is the partial decomposition of the biomass, thus creating a charcoal-like, high-energy dense substance with reduced moisture and a small particle size [8]. Bergman [59] described torrefaction as a pre-treatment technology that positively increases the possibility of using biomass in co-firing, thereby enabling biomass to compete directly with fossil fuels and provide an option for direct co-firing with a significant amount of torrefied biomass with minimal operating challenges. The co-firing system with torrefaction is shown in Fig. 7. Torrefied biomass has properties that are reasonably similar to coal, thereby making it more favorable for combustion and gasification purposes [59,60].

Pelletization and torrefaction complement each other in enhancing biomass co-firing [61]. These pretreatment technologies can contribute actively in controlling several issues associated with biomass co-firing such as the storage and feeding characteristics of the biomass and achieving a desirable handling size. Since torrefaction makes biomass properties more compatible with those of coal, it increases the possibility of substituting more coal with biomass in the combustor [62]. However, torrefied biomass has a low volumetric energy density, which may limit its use. It is recommended that biomass be pelletized in order to improve the fuel's volumetric energy density. Also, the torrefaction technology involves significant investment, which may increase the overall cost of generating electricity through biomass co-firing. Torrefaction also requires a large amount of biomass feedstock to compensate for the huge investment. Pyrolysis of biomass fuels can be carried out within a temperature range of 300–650 °C compared to 200–300 °C for torrefaction.

7.1.2. Advanced combustion technology

Except for biomass pretreatment, some advanced combustion technologies such as the volumetric combustion of biomass can enlarge the fuel diversity during combustion followed by enlarging biomass co-firing substitution ratios. The volumetric combustion concept is an air staging technique that leads to the thorough mixing of the gas species within the combustion chamber of the boiler based on the internal flue gas recirculation. The technology enables the secondary air to increase significantly by over 30% without leading to instability or incomplete combustion problems [47]. A large amount of secondary air is injected downward with an angle of inclination, delivering some of the flue gases to the primary combustion zone right from the secondary combustion zone. Due to the level of thoroughness of the internal recirculation of the flue gases, there is a uniform distribution of gas species and temperature inside the furnace that eventually results in combustion reactions through the whole furnace chamber with a low maximum flame temperature [47]. Accordingly, volumetric combustion can be characterized as a stable biomass combustion technology, one that improves the chance of biomass co-firing in

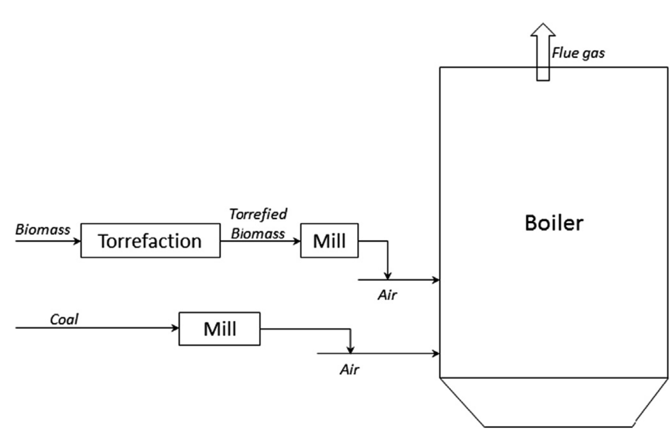

Fig. 7. Co-firing systems with torrefaction (adapted from [63]).

coal-fired power plants and that leads to significant reductions of both the thermal NO_x and fuel NO_x.

7.2. Policies

Biomass co-firing is usually more expensive than exclusively coal-firing because coal costs less than biomass. Different levels of government in both Canada and the US, as well as in several other countries, presently have various policy incentives and obligatory regulations aimed at increasing the overall contribution of renewable energy to their electricity sector. It is important to note that the existence of such policies enhance the competitiveness of biomass co-firing projects. For example, by making coal-based energy more expensive through measures like carbon pricing in the form of carbon taxation or emission cap-and-trade schemes, governments make biomass co-firing more attractive to utility companies [10].

Other measures that may significantly favor the development and adoption of biomass co-firing are different forms of government support and aid aimed at further developing the existing biomass supply infrastructure, the removal of subsidies associated with fossil fuels like coal, and the provision of sufficient funding for biomass co-firing research and development projects. Establishing mandatory quota obligation schemes for biomass in co-firing operations, as found in the Renewable Energy Portfolio Standards in a number of the United States, can also enhance co-firing technology and improve its attractiveness to utilities [10,34].

A summary of regulatory and environmental policies and measures that can enhance biomass co-firing is:

i. Carbon dioxide emission-reduction targets and tax incentives
ii. Environmental taxes and credits and renewable energy certificates (RECs)
iii. Permit requirements and specific site restrictions.
iv. Benefits from reduced sulfur dioxide and nitrogen oxides emissions
v. Policies favoring the disposal of biomass wastes
vi. Policies favoring the use of the ash
vii. Removal of fossil fuel subsidies
viii. Dedicated R&D funding for co-firing and support to biomass supply and co-firing infrastructure
ix. Establishing the mandatory use of biomass co-firing through quota obligation schemes [34].

8. Co-firing experience in North America

8.1. Biomass status in North America

North and Central America have an estimated forest area of 549 (10^6) ha representing nearly 26% of its land area. The cultivated plantations occupy less than 1% of these forest resources, while the remaining represents the abundant natural forest of the subcontinent. Based on the data represented in Table 4, the average area of forest and wooded land per inhabitant (i.e., the forest area per capita) of 1.1 ha indicates the potential contribution of wood to the energy supply of the countries involved. This is particularly substantial in some sub-regions such as the northwest part of North America (including Washington State and British Colombia) that have abundant forest resources. Generally, the possibilities of producing fuels derived from forest biomass vary significantly between regions across the continent [64–66].

The total above-ground biomass in forests in both North and Central America is 52 (10^9) tonnes, while its average above-ground woody biomass is 95 t/ha [64,66]. This is a representation of the total above-ground wood volume (m^3) and woody biomass (tonnes) in forest within this continent.

8.2. Existing co-firing plants in North America

Although there are many biomass co-firing operations in the United States, many are still at demonstration levels with different boiler types. Utility companies in the US are still reluctant to adopt co-firing at a commercial level, in part due to a lack of favorable incentives. However, there is a sudden interest in power generation and co-generation from biomass, waste, and recovered fuels within the power sector due to new environmental policies and regulations [17].

In Canada, biomass co-firing technology has developed quickly during the last ten years through efforts to increase biomass use in the country's electric utility sector. During this time various biomass fuel and coal co-firing projects have been evaluated and demonstrated successfully, especially in Ontario. IEA Bioenergy Task 32 [67] lists that as of early 2013, 47 biomass co-firing installations had been established in North America at either demonstration or commercial levels. So far, only 7 of these are in Canada (see Table 5). They are all based in Ontario and are owned and operated by the Ontario Power Generation (OPG). However, none of these 7 facilities is operating yet as they are being transformed to either solely natural gas-fired or biomass-fired plants [68].

Since 2003, the overall coal-fired power generation capacity in Ontario has been reduced by 40% as part of the province's drive to reduce the air pollution that results from this process as well as the negative perception of coal firing. It is expected that changes will lead to the reduction of nearly 30 megatonnes of carbon dioxide emissions in Ontario, which is equivalent to taking almost 7 million cars off the roads. The utility company directly involved, Ontario Power Generation (OPG), is aggressively seeking to add more renewable energy sources such as biomass and wind power, as well as natural gas-fired plants. Similar policies have been sought after in some other provinces, such as Nova Scotia, but that province's Renewable Electricity Plan, established in 2010, is being

Table 4
Forest resources, area (ha), above-ground biomass volume and biomass (m^3 and tonne) (adapted from [64]).

	Land area (ha) (10^6)	Forest area (ha) (10^6)	Ratio of forest area (%)	Plantations (ha) (10^6)	Forest area per capita (ha)	Volume (m^3/ha)	Volume (m^3) (10^9)	Woody biomass (tonne/ha)	Woody biomass (tonne) (10^9)
Africa	2978	649	21.8	8	0.8	72	46	109	70
Asia	3084	547	17.8	115	0.2	63	34	82	44
Europe	2259	1039	46.0	32	1.4	112	116	59	61
North and Central America	2136	549	25.7	2	1.1	123	67	95	52
Oceania	849	197	23.3	3	6.6	55	10	64	12
South America	1754	885	50.5	10	2.6	125	110	203	179
World	13063	3869	29.6	171	0.6	100	386	109	421

Table 5
Biomass co-firing installations in Canada (adapted from [67]).

Location	Plant name	Owner	Co-firing type	Boiler	Burner configuration	Output (MWe)	Primary fuel	Co-fired fuel (s)
Ontario	Atikokan	OPG	Direct	PF	Front wall	227	Lignite	Wood pellets
Ontario	Lambton 1	OPG	Direct	PF	Tangential	500	Pulverized coal	Dry distillers and grain
Ontario	Nanticoke 4	OPG	Direct	PF	Opposed wall	500	Blended coal	Agricultural residues
Ontario	Nanticoke 6	OPG	Direct	PF	Opposed wall	500	Blended coal	Agricultural residues and wood pellets
Ontario	Nanticoke X	OPG	Direct	PF	Opposed wall	500	Blended coal	Wood pellets
Ontario	Thunder Bay 2	OPG	Blended on coal pile	PF	Tangential	155	Lignite	Wood pellets
Ontario	Thunder Bay 3	OPG	Direct	PF	Tangential	155	Lignite	Grain screenings

Table 6
Summary of recent co-firing activities (coal plant conversions and repowering) in North America (adapted from [71]).

Location	Plant name	Owner	Co-fired fuel (s)	Description
Bakersfield, California	Mount Poso Cogeneration Plant	Red Hawk Energy	Agricultural and residential waste	Expected conversion date is September 2010
Boardman, Oregon	Boardman Plant	Portland General Electric	Torrefied wood or other biomass	Plan to operate coal plant until 2020, then close.
Portsmouth, New Hampshire	Schiller Station	Public Service Co. of NH	Wood	In operation since December 2006; burns approx. 400,000 t/year in fluidized bed boiler
Cassville, Wisconsin	E.J. Stoneman	DTE Energy	Wood	Plan to convert a 50 MW-coal plant entirely to wood
Hawaii	Hu Honua Station	Hu Honua Bioenergy, LLC	Agricultural residues	24-MW facility burning local wood and agricultural wastes
Ashland, Wisconsin	Bay Front Station	Xcel Energy	Wood waste from forest harvesting	After repowering, will burn biomass in all three boilers
Charter St. Heating Plant	Madison, Wisconsin	University of Wisconsin	Various biomass fuels	Refire coal boilers with biomass or natural gas; install a new boiler to burn 100% biomass
Mitchell Steam Generating Plant	Albany	Southern Company	Woody biomass	Plan to convert 163 MW coal plant to biomass
Shadyside, Ohio	R.E. Burger Plant	First Energy Corp. (Ohio Edison)	Variety of biomass fuels	Plan to repower two coal units to biomass (up to 312 MW of total biomass energy)
Ontario, Canada	Lakeview Station	Ontario Power	Agricultural residues and wood pellets	Plan to phase out coal generation in Ontario by 2014
Ontario, Canada	Lambton Station	Ontario Power	Agricultural residues and wood pellets	Plan to phase out coal generation in Ontario by 2014
Ontario, Canada	Nanticoke Station	Ontario Power	Agricultural residues and wood pellets	Plan to phase out coal generation in Ontario by 2014
Ontario, Canada	Atikokan Station	Ontario Power	Agricultural residues and wood pellets	Plan to phase out coal generation in Ontario by 2014

hindered by the need to protect the sustainability of the province's forests [68,69].

Recently many utility companies in the United States and Canada have indicated their intentions to begin biomass co-firing, especially with coal, using different biomass fuel types, co-firing technologies, and levels (see Table 6). The goal is to achieve higher levels of co-firing in an existing co-firing system or to repower an entire coal plant to run on biomass [64]. The co-firing options used by these utility companies are: (a) co-fire at low biomass rates with little equipment modification; (b) co-fire at higher biomass rates with equipment upgrades; (c) convert/repower individual coal burners to be fired with biomass; (d) convert/repower entire coal plants to be fired with biomass; (e) co-fire with torrefied wood [70].

8.3. Comparative assessment of co-firing in North America and around the world

As mentioned earlier in this paper, significant biomass co-firing projects have been established in many parts of the world, both at demonstration and commercial levels, especially in the past decade. Presently, there are over 150 biomass co-firing installations in the world, with roughly two-thirds of them in Europe. The rest are based mostly in North America and Australia [67]. More progress in terms of use and results has been recorded among European utility companies, especially in countries like the Netherlands, Denmark, Finland, and the United Kingdom, than in North America. For example, biomass and coal have been co-fired in many boiler types in the Netherlands for the past ten years [8]. Incentives and favorable environmental policies and regulations are the major factors encouraging the recent interest in power generation and co-generation from biomass energy sources especially in most European countries [8]. Despite the remarkable commercial success of biomass co-firing in many European countries, most of the biomass co-firing in North America is still limited to demonstration levels. Based on the research carried out, the authors attribute this slow progress to the absence of appropriate incentives and regulatory policies to make the technology better able to compete adequately with conventional power generation technologies. At present coal, natural gas and nuclear power generation systems are viewed by most stakeholders in the North American power generation industry to offer better economic, environmental, and technological benefits than biomass co-firing. Secondly, the slow adoption is believed to be influenced by the challenge associated with guaranteeing a stable and cheap supply of biomass a continuous operation of the systems, where improving and optimizing the biomass delivery system can contribute to improving the co-firing efficiency significantly.

9. The future of biomass co-firing

Biomass is considered to be an unreliable energy source due to the challenges posed by its unstable supply [33]. In recent years, many efforts have been made in different continents to cultivate

biomass crops for energy purposes in order to improve the reliability of this source of energy. Such efforts are is backed up by advanced research carried out in many parts of the world to develop more efficient biomass conversion technologies [34].

The investment required to adapt or retrofit an existing power plant to co-fire a biomass feedstock is generally low compared to the cost of building a new one or building a dedicated biomass power plant. Biomass co-firing even offers higher overall environmental and economic value when used to produce useful heat in addition to power in combined heat and power plants (CHP) in industrial facilities or for district heating networks [72,73].

In addition to reducing GHG emissions, biomass co-firing enables highly efficient power generation in modern, large power plants. This is because the total energy efficiency achieved in co-fired plants is usually much higher than that of dedicated biomass power plants. This may be further improved if biomass co-firing takes place in combined heat and power (CHP) plants [7,20].

A sustainable biomass co-firing project is highly dependent on a stable and cheap flow of biomass. In other words, the economic feasibility of co-firing biomass with either coal or natural gas is determined by the costs of biomass acquisition and transportation. Many factors affect the acquisition costs of a biomass feedstock such as local availability of large quantities of cheap biomass as well as possible competition with other biomass energy and non-energy uses. If these biomass materials are locally available in large quantities and at low prices, then biomass co-firing is economically attractive. However, high energy-dense, pre-treated biomass feedstocks such as wood pellets may be used when local sources are insufficient since such feedstocks are better suited for long-distance transportation than ordinary biomass feed stocks [10].

Based on the work done by the OPG in biomass co-firing, any successful commercial biomass co-firing project in North America must develop a sustainable supply of the biomass fuel(s) and effective fuel transportation and must also complete any plant modifications needed to achieve successful operations. All of this requires contributions from many groups including government, utility companies, forestry, agriculture, academic and research institutions, and communities. The use of biomass as a power generation fuel will create new market opportunities for the agricultural and forestry industries and for communities in many parts of the country, especially in Western Canada, which is very rich in forest resources. The use of biomass will also enable old coal power plants to continue to be used even after coal is phased out in the near future [68].

In order to encourage the use of biomass fuels, national and regional governments should devise favorable regulatory and environmental policies to make fossil fuel-based energy more expensive. For example, a recent European Union Emissions Trading System (EU ETS) policy aimed at increasing co-firing competitiveness and the use of pellets in power plants in Europe enables major coal-power plant owners to auction their CO_2 allowances. Also, another European Union policy mandates its member states to achieve an expected level of renewable energy use by 2020. Similar policies and measures exist in several states in the United States of America. The lack of specific incentives is seen as the main reason behind the slow growth in the implementation of co-firing technology in Canada and Australia compared to European countries. Policies designed to enhance the efficient use of biomass, such as encouraging co-firing in CHP plants where district heating systems and connections with industrial facilities are available, should be adopted [10,48].

10. Conclusions

Successful projects both at demonstration and commercial levels, especially in Europe and North America, have shown that co-firing biomass fuels with fossil fuels can be a transitional option towards completely carbon-free power.

Biomass co-firing can be done through direct co-firing, indirect co-firing, and parallel co-firing. Most of these pathways are mature technologies, although there are a few innovations and developments. Generally, biomass co-firing levels are still within 5–10% on a continuous operational basis in most commercial operations.

The presence of biomass in the combustor can reduce overall GHG emissions as well as NOx and SOx from existing coal-fired and gas-fired power plants. Several other advantages, such as a reduction in biomass waste and soil and water pollution and in the overall cost of the base fuel, may benefit the utility companies and the environment. In addition, co-firing has lower initial capital costs since it uses existing facilities. However, the plant's operational and maintenance costs may eventually be higher than those of a dedicated coal-fired power generation plant.

Biomass co-firing may further reduce GHG emissions in North America because many regions are rich in biomass resources that can ensure a sustainable supply base. However, in order to effectively exploit the potential offered by co-firing, urgent measures and policies are needed to address several technical and logistical issues. Firstly, a harmonized system between all the relevant stakeholders is needed to ensure the long-term sustainability of high-quality biomass fuels. Secondly, there have to be favorable policies, preferably in the form of subsidies and tax exemptions, as well as a regulatory framework mandating GHG reductions.

Finally, there should be sustained research and development programs with a focus on resolving the issues and challenges that have been identified in this paper. The future of biomass co-firing in North America, especially in Canada, depends on the ability to address these issues, along with policy incentives and mandatory regulations that enable power utility companies to take advantage of the opportunities in this sector.

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